

An Economic Scoping Study for CO₂ Capture Using Aqueous Ammonia



Prepared By:

Jared P. Ciferno

National Energy Technology Laboratory

Philip DiPietro

Advanced Resources International

Thomas Tarka

Energetics Incorporated

Final Report

Revised February 2005

An Economic Scoping Study for CO₂ Capture Using Aqueous Ammonia

Executive Summary

This technical and economic scoping analysis compares CO₂ capture from flue gas using an aqueous ammonia (AA) chemical sorbent to state-of-the-art amine technology. The analysis is based on research into AA-based CO₂ capture conducted at NETL's Carbon Sequestration Science Focus Area. CO₂ capture is considered as a part of a multi-pollutant control system applied to a grass-roots coal-fired power plant.

Like amine, the AA system is a liquid chemical sorbent, but AA technology has two key advantages. First, aqueous ammonia is less expensive than amines (\$0.30/lb CO₂ carrying capacity versus \$3.8/lb CO₂) which will lower chemical make-up costs. Second, AA has a lower heat of reaction for regenerating the chemical sorbent (262 Btu/lb CO₂ captured versus 825 for mono-ethanol amine). Assuming similar benefits from heat integration between the two CO₂ capture processes, the aqueous ammonia process is estimated to use 500 Btu of steam per lb CO₂ captured compared to 1,621 Btu for amines.

It is estimated that aqueous ammonia technology can reduce the heat rate of a PC power plant equipped for CO₂ capture from 11,896 Btu/kWh (amine capture) to 10,140 Btu/kWh. The CO₂ compression load is nearly the same in both cases, but the parasitic consumption of steam is 67% less in the AA case. The capital cost is reduced from \$2,231/kW to \$1,800/kW, partially due to the cascading effect of improved efficiency. AA also offers lower net cost for SO₂, NO_x, and mercury control that benefits the economics of a multi-pollutant system. Fertilizer by-product offers net revenue of 0.50 cents/kWh and the reduced cost for capturing mercury, negligible for AA and \$7,000/lb mercury for a carbon adsorbent system provides 0.04 cents/kWh of savings.

In a supercritical power plant with a multi-pollutant control system, aqueous ammonia has the potential to provide a net cost of CO₂ capture of \$14/metric ton of CO₂ emissions avoided (a 21% increase in COE compared to a pulverized coal power plant without CO₂ capture). However, in an ultra-supercritical steam cycle, aqueous ammonia has the potential to provide a net cost of CO₂ capture of \$13/metric ton of CO₂ emissions avoided with only an 18% increase in COE. The current cost of CO₂ capture using amines is \$47/metric ton of CO₂ emissions avoided (a 67% increase in COE relative to a PC power plant without CO₂ capture). Research challenges include accommodating the flue gas temperature of 130°F, which is hotter than optimal for aqueous ammonia capture, and minimizing ammonia loss in the absorption tower and ammonia slip out the stack.

Background: Analysis Goals and Methodology

The Carbon Sequestration Program at NETL has set the following goals for technologies developed under its CO₂ capture research portfolio [1]:

- Technologies for CO₂ capture from combustion-based steam power plants should capture at least 90% of CO₂ emissions while increasing the cost of electricity by no more than 20%
- Technologies for CO₂ capture from gasification-based systems should capture at least 90% of CO₂ emissions while increasing the cost of electricity by no more than 10%.

This analysis is one of several being conducted to determine the degree to which selected CO₂ capture technologies have the potential to achieve the program goals and to establish a framework for evaluating

progress toward the goals. The aqueous ammonia concept is being pursued within NETL's Carbon Sequestration Science Focus Area [2].

Research on aqueous ammonia use for CO₂ capture is at a very early stage, and a detailed system analysis at this time is not possible. Instead, an economic scoping study has been conducted to quantify the potential benefits of this technology. Our methodology is to develop a heat and material balance for a base case pulverized coal (PC) fired plant with amine-based CO₂ capture, using data from published studies [3, 4]. Then, the performance of the new technology is compared to that of the amine system by developing a heat and material balance and an estimate of the differences in capital and operating cost relative to the base case amine. Where possible, design heuristics (i.e. rules of thumb or guidelines from published papers) were used to estimate flows and sizes of equipment. However, some sizing and costing algorithms are employed for specific equipment such as CO₂ compressors and gas/liquid contact towers. For this initial assessment, a rigorous modeling of unit operations was not performed. This is an area for later work as development of the technology progresses.

Figure 1 shows the system boundary used for this analysis. In estimating the impact of CO₂ sequestration on the cost of electricity, the cost and energy consumption of pipeline transport for 10 miles and injection into a saline formation 1,500 ft below the surface was included. The CO₂ transport and storage performance/economics were based off data presented in a recent DOE/TVA study entitled, "Economic Evaluation of CO₂ Storage and Sink Enhancement Options" [16]. The revenue from by-products, which is an important consideration in the aqueous ammonia analysis, was also assessed and incorporated into the economics.

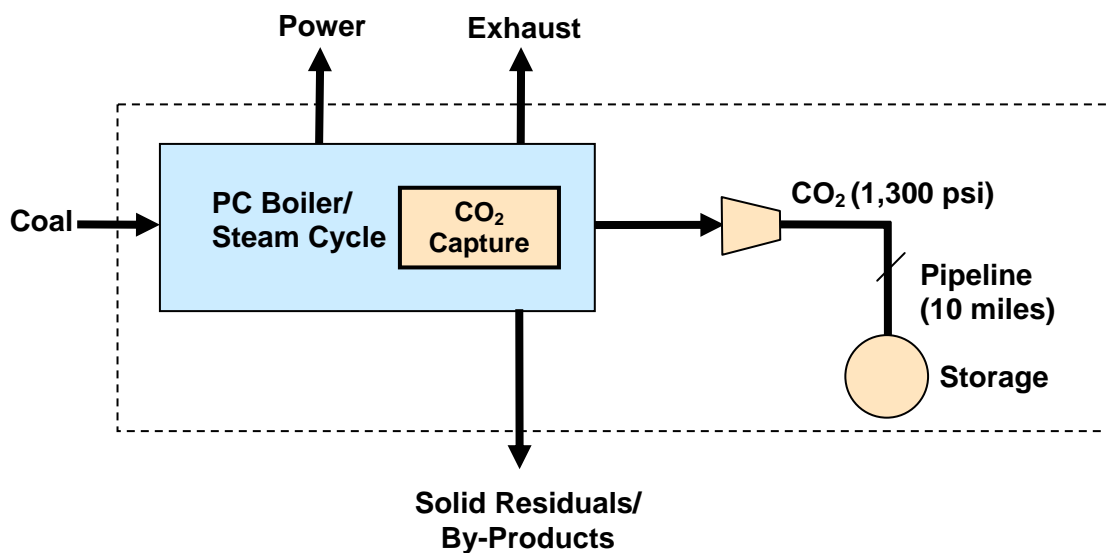


Figure 1. Analysis Boundary

Base Case PC Plant with Amine-based CO₂ Capture

Aqueous ammonia capture of CO₂ is compared to a base case PC plant using conventional amines. A spreadsheet model was developed that is consistent with a previous DOE/EPRI study (Case 7A from [3]) extrapolated to 400 MW net power output. The DOE/EPRI study is based on a supercritical pulverized coal boiler with a net amine reboiler steam consumption of 1,621 Btu/lb of CO₂ captured. Figure 2 and Table 1 show outputs from the model's amine capture case. Parasitic or auxiliary load, shown as 92 MW in Figure 2, is the electric power used to operate pumps, compressors and other equipment in the power plant.

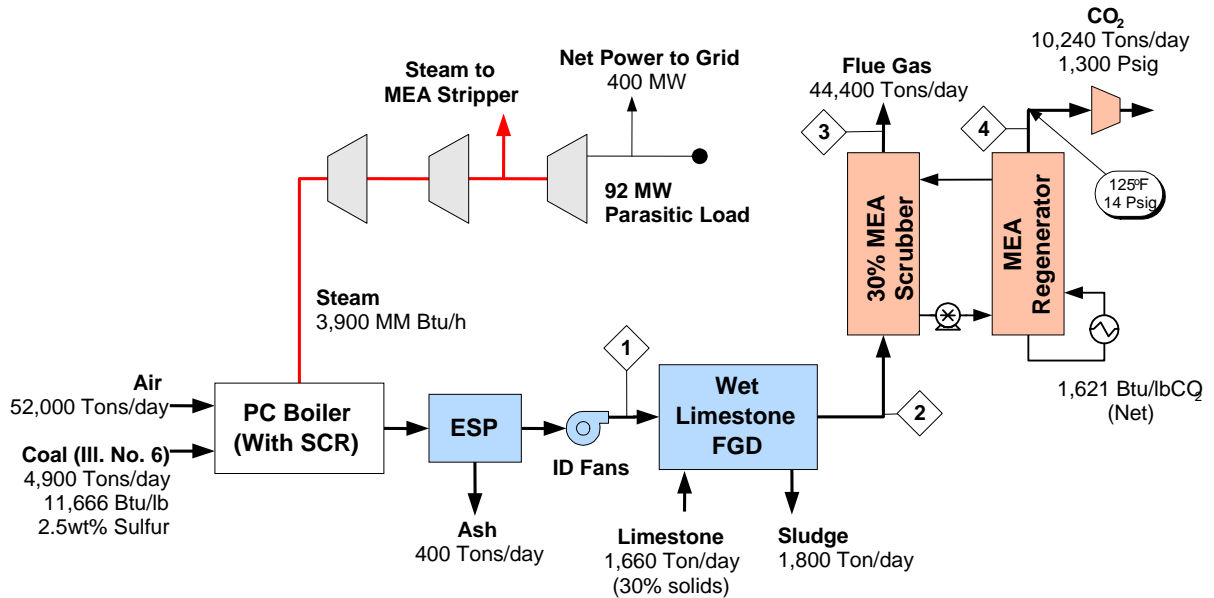


Figure 2. PC Power Plant with Amine CO₂ Capture (DOE/EPRI Case 7A [3])

Table 1. Selected Process Flow Rates and Compositions

		1	2	3	4
		Boiler Effluent	Absorber Inlet	Flue gas Exhaust	CO ₂ Product
Temperature, °F		281	131	136	125
Pressure, psia		14	17	14	1,500
Volume %	CO ₂	14%	12%	2%	100%
	O ₂	3%	3%	4%	0%
	N ₂	74%	70%	77%	0%
	H ₂ O	8%	14%	16%	0%
	SO ₂	0.2%	4.1 ppm	0%	0%
	Argon	1%	1%	1%	0%
Molar flow (lbmoles/hr)		153,383	153,066	133,790	19,500
Vol. flow (10 ⁶ ACFM)		1.57	1.05	1.12	0.0011
Mass flow (tons/day)		55,346	54,602	44,424	10,240

Figure 3 presents a more detailed look at the amine capture system. The size and cost of the absorber tower are functions of the actual volumetric flow rate of flue gas (1.05 million scfm) and percent CO₂ removal (90%). CO₂ in the flue gas is reduced from 14 vol% to 2 vol%. The size and cost of the CO₂ stripper are primarily functions of the amine solution volumetric flow rate, which is calculated from the concentration difference between the rich amine solution (30 wt% MEA, 9.7 wt% CO₂) and the lean amine solution (4.3 wt% CO₂) [5, 6, 7]. The steam load for the amine stripper reboiler is large and pulls steam from the low-pressure turbine as shown in Figure 2. The reboiler provides the net sensible heat required, the heat of reaction, and the heat for stripping steam. The reported 1,621 Btu/lb of CO₂ is the enthalpy change in the steam across the reboiler.

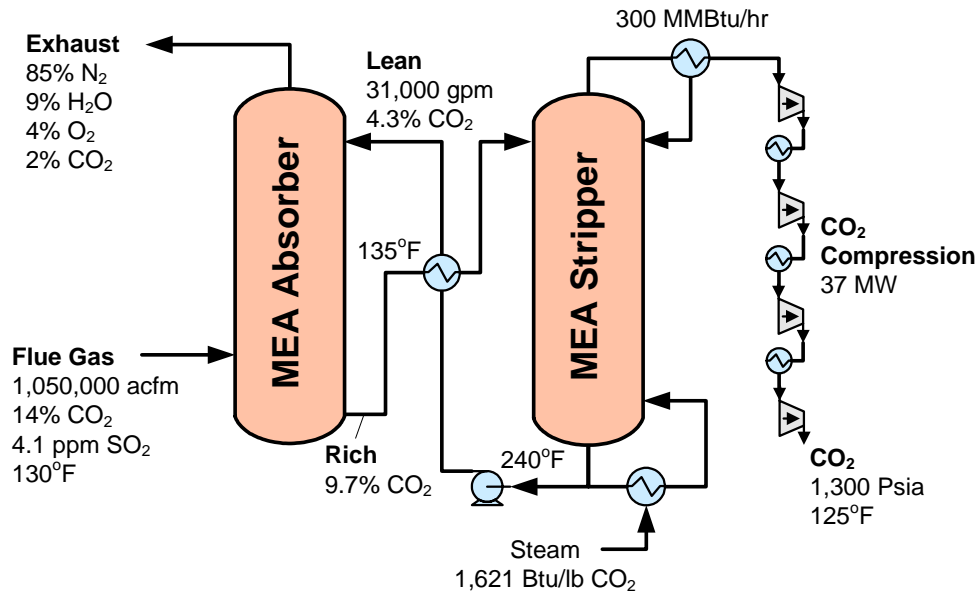


Figure 3. Amine Capture System used in the PC Base Case

Figure 4 shows the size of the CO₂ capture equipment relative to the boiler. This gives a sense of the magnitude of impact that CO₂ capture will have on a PC power plant.

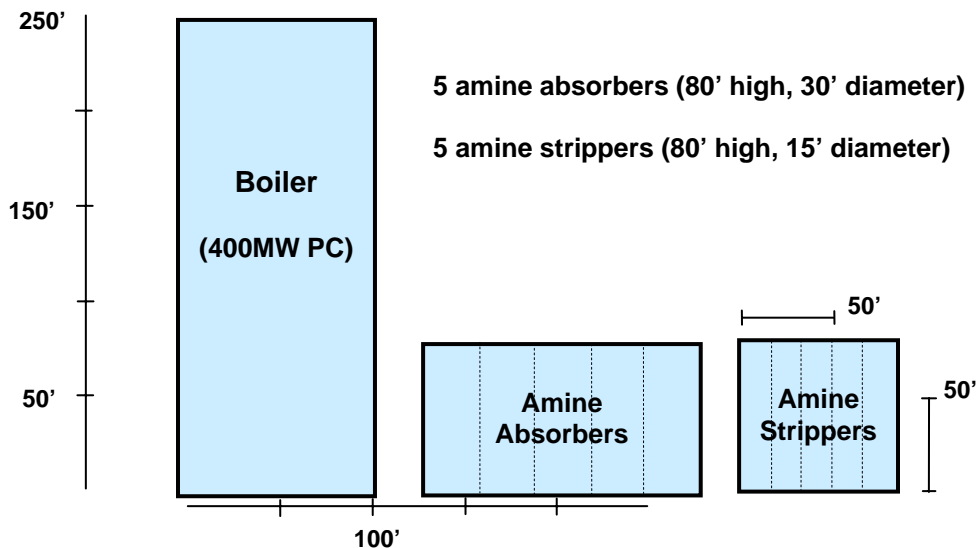


Figure 4. Amine CO₂ Capture Relative Equipment Sizing

A discounted cash flow model was developed that inputs the capital expenditures for a 400 MW PC power plant, variable operating costs including coal use and chemical makeup, fixed operating costs, and by-product revenues. Using a plant economic life of 20 years and a capital charge factor of 14.8%, a cost of electricity that balances expenditures and revenues was calculated. Table 2 shows the results from the cash flow analysis, which closely replicates the results from the DOE/EPRI study [3]. The cost of electricity goes from 4.6 cents/kWh in the no-capture case to 7.6 cents/kWh in the MEA capture case, a 67% increase.

Table 2. Economic Results

		No CO ₂ Capture	MEA CO ₂ Capture
CO₂ Capture	Base Plant (\$/kWe)	1,072	1,460
	Gas Cleanup (\$/kWe)	197	239
	CO ₂ Capture (\$/kWe)	-	310
	Compression (\$/kWe)	-	122
	Total (\$/kWe)	1,270	2,132
	Capital COE (c/kWh)	2.68	4.50
	Variable COE (c/kWh)	1.90	2.91
	Total COE (c/kWh)	4.58	7.41
	\$/tonne CO₂ Avoided	-	43
Including CO₂ Transportation and Storage*			
Total	Total Capital (\$/kWe)	1,270	2,231
	Total \$/tonne CO₂ Avoided	-	47
	Total COE (c/kWh)	4.58	7.64
	Increase in COE	-	67%
Basis: 90% CO ₂ Capture, 80% Capacity Factor, 2003 Dollars, Coal \$28/ton			
*CO ₂ Compression to 1,300 Psig, Transport 10 miles and Stored in Saline Formation 1,500 ft			
Sources: NETL Carbon Sequestration Economic Model; Evaluation of Innovative Fossil Fuel Power Plants with CO ₂ Removal, DOE/EPRI, 1000316			

The overall performance for both cases is presented in Table 3. As shown, the current state of amine CO₂ capture is very energy intensive requiring an additional 56.5 MW for capture and compression (an additional 1,415 ton coal/day and approximately 30% decrease in efficiency).

Table 3. Power Plant Performance

		No CO ₂ Capture	MEA CO ₂ Capture
Total Gross Power (MWe)		425	492
Auxiliary Load (MWe)	Base Plant	22.1	28.1
	CO ₂ Capture	-	21.3
	CO ₂ Compression	-	35.2
	NO _x and SO _x	3.1	4.2
	Transport & Storage	-	2.7
	Total	25	92
Net Power		400	400
Coal Flowrate (ton/day)		3,480	4,895
Net Heat Rate (Btu/kWh, HHV)		8,453	11,896
Efficiency		40%	29%
Energy Penalty		-	29%
Energy Penalty: Percent decrease in power plant efficiency due to CO ₂ capture			

PC with Aqueous Ammonia CO₂ Capture

AA is used in commercial applications to capture SO₂ from power plant flue gas. Marsulex and Alstom Power both offer commercial processes for SO₂ removal using ammonia. Powerspan Corp. recently conducted a commercial-scale demonstration of an AA-based multi-pollutant control technology called “ECO™” for scrubbing SO₂, NO_x, and mercury from flue gas.

The following advantages of the aqueous ammonia process compared to conventional amines have been identified: (1) reduced steam load, (2) more concentrated CO₂ carrier, (3) lower chemical cost, and (4) multi-pollutant control with salable by-products. The impact of each is discussed below.

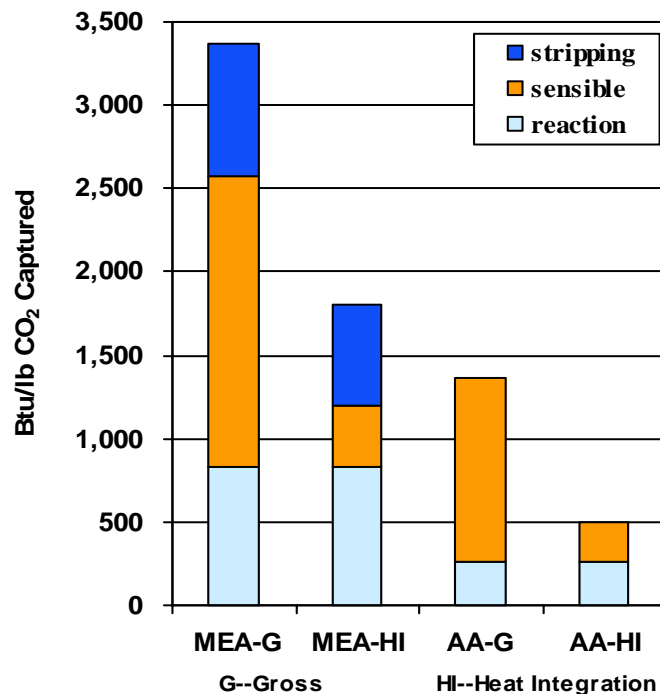
1) *Reduced steam load.* In a system that captures and releases CO₂ by cycling between carbonate and bicarbonate, the heat of reaction is reduced to 262 Btu/lb CO₂, which is much less than the 825 Btu/lb CO₂ needed with MEA [Appendix A]. Also, it is possible that the carbonate/bicarbonate system will exhibit a higher CO₂ carrying density than MEA (carrying density is the delta in CO₂ weight percent between rich and lean solutions), reducing sensible heat requirements. Finally, it is possible the carbonate/bicarbonate system may require little or no stripping steam for regeneration, compared to one mole steam per mole of CO₂ captured typical of amine systems. Figure 5 compares the heat requirements for an MEA CO₂ capture system versus one using aqueous ammonia. The total heat requirement

is divided into heat of reaction, sensible heat, and stripping steam. Figure 5 shows that heat integration enables significant reduction in the net heat requirement for the amine system. The gross heat requirement for an aqueous ammonia system was calculated, and heat integration savings similar in magnitude to those achieved by the amine were assumed. For example, the gross turbine heat rate for the MEA-HI CO₂ capture is estimated to be 9,672 Btu/kWh, and for the AA-HI CO₂ capture the estimate is 8,482 Btu/kWh, a 12% improvement in gross turbine heat rate.

2) *More concentrated CO₂ carrier.* In addition to affecting sensible heat, the CO₂ carrying density also affects the size of the CO₂ absorber and the circulation pump size and load. Laboratory data from NETL indicate the carbonate/bicarbonate system could exhibit a carrying capacity of 0.068 lb CO₂ per lb solution versus 0.054 for amines. Based on cost and sizing heuristics, the reduced liquid flow lowers the stripper cost from \$36.4 to \$25.2 million (four strippers in parallel vs. five) and reduces the circulation pump power requirement from 1.8 to 1.2 MW.

3) *Lower chemical cost.* Amine costs are estimated to be \$1,360/ton (\$1.5/kg), which is high compared to anhydrous ammonia at \$263/ton (\$0.29/kg). The calculations below show that ammonia is roughly a factor of ten less expensive per unit of CO₂ absorption capacity.

Figure 5. Heat Requirements for CO₂ Capture



Mono-ethanolamine Cost:

$$\left(\frac{\$0.6803}{lbMEA} \right) \times \left(\frac{0.3lbMEA}{lbSolution} \right) \times \left(\frac{lbSolution}{.054 lbCO_2} \right) = \frac{\$3.78}{lbCO_2}$$

Aqueous Ammonia Cost:

$$\left(\frac{\$0.1315}{lbNH_3} \right) \times \left(\frac{0.15lbNH_3}{lbSolution} \right) \times \left(\frac{lbSolution}{0.068 CO_2} \right) = \frac{\$0.29}{lbCO_2}$$

The cost of the absorbent is particularly important for coal-fired power plant applications, where residual SO₂, SO₃, and other species cause solvent degradation. For amines, the attrition was estimated from the following heuristics: general loss of 3.2 lb MEA/ton CO₂ (1.6 kg MEA/tonne CO₂), and SO_x loss of 2 mole MEA/mole SO_x in absorber inlet [7]. Based on normal limestone scrubber operation removal (98%), amine make-up costs could be \$60/ton CO₂ captured. A \$7.5/CO₂ was assumed for aggressive limestone scrubbing (4.1 ppm SO₂ in the effluent), recognizing that flue gas treatment options to reduce SO_x upstream from the CO₂ absorber may be cost effective. A detailed analysis to accurately estimate ammonia attrition has not been performed. Instead, it was assumed that it will be similar on a molar basis to amine and that the total cost will be less because of the lower cost of ammonia. Furthermore, the reaction by-products can be sold as fertilizer, so there is no ammonia penalty for their production; however, there are expected to be small ammonia losses in the exhaust gas.

4) *Value-added by-products.* The use of ammonia-based systems to react NO_x and SO_x in flue gas to form fertilizer (ammonia sulfate, (NH₄)₂SO₄ and ammonia nitrate, NH₄NO₃) has been demonstrated at commercial scale. A comparison of an amine system plus an SCR (Selective Catalytic Reduction) unit and limestone scrubber to an aqueous ammonia system in which ammonia is used for NO_x, SO_x, and CO₂ control was made. Table 4 compares the aqueous ammonia process to a limestone scrubber. It has advantages if there is a market for the byproduct fertilizer, which is primarily ammonium sulfate (AS). The domestic market for ammonium sulfate is roughly 2 million tons/yr [8]. One 400 MW coal-fired power plant with AA SO₂ control will produce about 100,000 tons AS per year. Therefore, twenty power plants could supply all the AS currently used by the domestic market. However, as domestic SO₂ emissions have been reduced, the need for additional sulfur fertilizer has grown, and this trend is likely to continue. The domestic and international markets for nitrogen fertilizers are 12 and 83 million tons per year [9] respectively, so the worldwide potential for the aqueous ammonia fertilizer byproduct is significant. Also, at the right price, ammonium sulfate could displace urea or other forms of nitrogen fertilizer.

Table 4: Aqueous Ammonia versus Limestone Scrubbers for SO_x Control

	Limestone Scrubber	Aqueous Ammonia
Parasitic Load (MWe)	4-7	4-7
Reactant Consumption (\$/ton SO₂)	22	136
By-Product Revenue (\$/ton SO₂)	0	314
Net Material Revenue (\$/ton SO₂)	-22	178
Basis: Limestone at \$13/ton [3, 10], Anhydrous ammonia \$255/ton [12], no market for FGD sludge, Ammonia sulfate at \$152/ton [12]		

Capturing NO_x is more difficult than capturing SO₂. In order for aqueous ammonia to react with NO_x, NO, which is 95% of the NO_x, must be oxidized to NO₂. This requires another unit operation or use of an oxidant, such as ozone. The NO oxidation process represents a significant cost. However, when NO is oxidized, some elemental Hg in the flue gas will also be oxidized, enabling it to be captured in the aqueous ammonia solution and removed from the flue gas. The aqueous solution containing mercury, ammonium nitrate and ammonium sulfate would be run through a carbon adsorbent bed to remove the mercury so that it does not contaminate the fertilizer. The current cost estimate for carbon-based mercury capture in flue gas is estimated at between \$50,000 and \$70,000/pound [14]. This analysis assumes that mercury control will be required and that there is a 10 percent increase in removal efficiency with the ECOTM process compared to conventional technology. Therefore, a credit of \$7,000/lb Hg removed was allocated to the aqueous ammonia process.

Table 5 shows the relative operating cost impact of the by-products. The first thing to note is that the flow rate of CO₂ is very large compared to the other species. Even if revenues from one of the by-products is high on a per pound basis, it is low on a per ton of CO₂ captured basis. At this time, the value of the avoided cost of mercury control is highly uncertain.

Table 5: By-product Flows and Revenues for Multi-Pollutant Control Using Aqueous Ammonia

	Production Rate (lb/kWh)	Value (\$/ton)	Feedstock Cost (\$/ton)	Operating Revenue (\$/ton)	Operating Revenue (cents/kWh)	Revenue (\$/ton CO ₂ captured)
Ammonium Nitrate	0.0016	175	90	85	0.009	0.10
Ammonium Sulfate	0.091	152	66	86	0.493	5.3
Mercury	5.9E-8	14E+6	0	14E+6	0.038	.45
Carbon Dioxide	1.70	--	--	--	--	--
Basis: 80% Capacity Factor						

Aqueous Ammonia Multi-pollutant Capture System

Figure 6 shows outputs from the spreadsheet model for the aqueous ammonia multi-pollutant capture case. This analysis assumes NO_x and elemental mercury are oxidized by the reactor in the ECOTM system after exiting the particulate filter [14]. The flue gas is contacted with aqueous ammonia to form ammonia nitrate, ammonia sulfate, and a non-gaseous mercury specie. The solution is then passed through an activated carbon bed for mercury removal before passing to a crystallizer and granulator for solid fertilizer production. CO₂ is removed from the flue gas in an ammonia scrubber, and then compressed to 1,300 psi for injection.

The boiler island and power cycle shown in Figure 6 are those of a supercritical steam cycle system, modeled from Cases 7A and 7C presented in a recent DOE /EPRI study [3]. The gross turbine heat rate using MEA to capture CO₂ (Case 7A) is 9,672 Btu/kWh compared to 7,951 Btu/kWh for the no capture case (7C). The 1,721 Btu/kWh increase in turbine heat rate is attributed to steam used for MEA regeneration. Due to less regeneration steam required for AA regeneration, the gross turbine heat rate was estimated to be 8,482 Btu/kWh (12% lower than the MEA case). An analysis using AA on an ultra-supercritical steam cycle (USC) was also carried out using Cases 7B and 7D of reference [3]. The USC cycle efficiency combined with a lower steam requirement for AA regeneration (compared to MEA)

results in a gross turbine heat rate of 8,031 Btu/kWh for the CO₂ capture case. Tables 6 and 7 present the performance and economics for the supercritical and ultra-supercritical CO₂ cases.

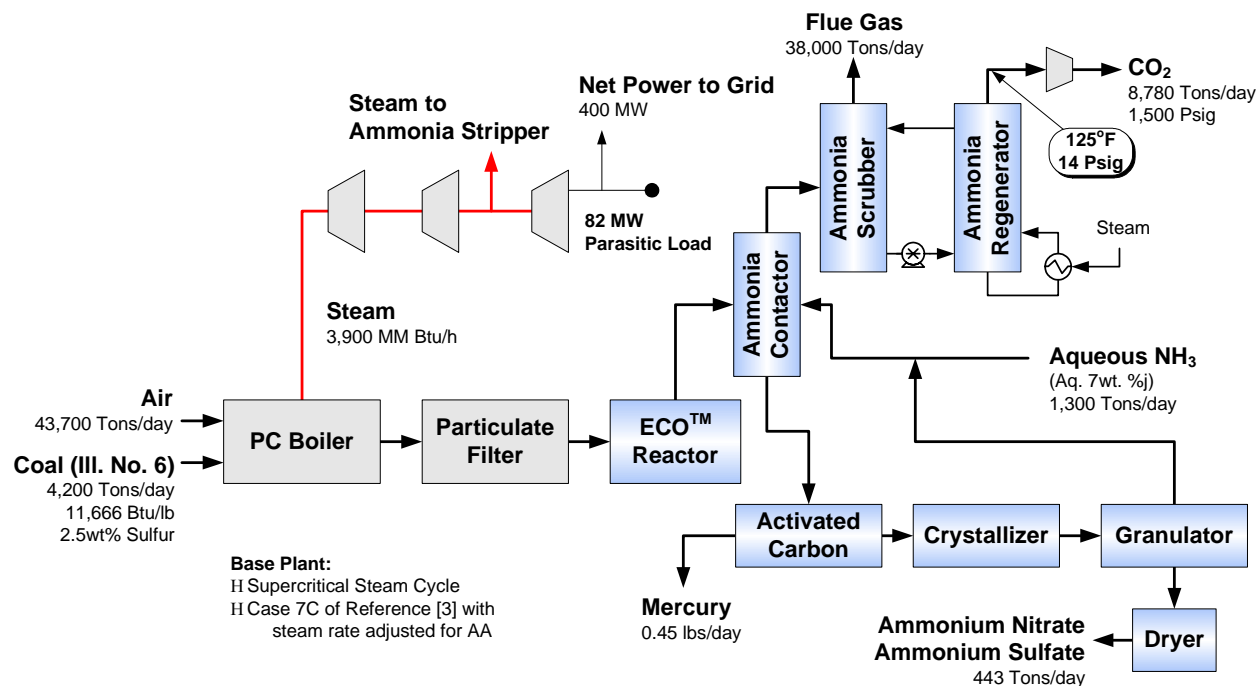


Figure 6. PC Power Plant with Aqueous Ammonia Multi-pollutant Control System

Table 6. Power Plant Performance

Case		1	2	3	4	5	6
Sorbent		None	MEA	AA	AA	AA (USC) ¹	AA (USC) ¹
Component(s) Removed		None	CO ₂	CO ₂	CO ₂ , SO _x , NO _x , Hg	CO ₂	CO ₂ , SO _x , NO _x , Hg
Total Gross Power (MWe)		425	492	478	482	473	476
Auxiliary Load (MWe)	Base Plant	22.1	28.3	27.3	27.5	25.1	25.3
	CO ₂ Capture	-	21.4	14.5	10.3	13.6	10.2
	CO ₂ Compression	-	35.3	30.0	30.2	28.1	28.3
	NO _x and SO _x	3.1	4.4	3.8	11.0 ²	3.5	10.3 ²
	Transport & Storage	-	2.9	2.5	2.5	2.3	2.3
	Total	25	92	78	82	73	76
Net Power		400	400	400	400	400	400
Coal Flowrate (ton/day)		3,480	4,895	4,172	4,200	3,904	3,935
CO₂ Captured (ton/day)		-	10,240	8,727	8,789	8,168	8,233
Net Heat Rate (Btu/kWh, HHV)		8,453	11,896	10,139	10,211	9,489	9,565
Fertilizer Production (ton/day)		-	-	-	443	-	415
Efficiency		40%	29%	34%	34%	36%	36%
Energy Penalty		-	29%	17%	17%	16%¹	16%¹

Energy Penalty: Percent decrease in power plant efficiency due to CO₂ capture
¹Ultra-supercritical steam cycle; USC base case no-capture is 43% efficient
²Auxiliary load for the multi-pollutant removal ECO is ~11 MW

Results

The overall performance for the supercritical and ultra-supercritical cases is presented in Table 6. As shown, the current state (Case 2) of amine CO₂ capture is very energy intensive, requiring 57 MW for capture and compression (an additional 1,415 ton coal/day and approximately 30% decrease in efficiency). The benefits of higher CO₂ capacity and lower heat of reaction (compared to MEA) using aqueous ammonia results in a 15% decrease in parasitic load (from 92MW to 78MW) and 15% decrease in net power plant heat rate for Case 3. The same proportional amount of energy savings is also obtained in the ultra-supercritical cases (5 and 6) with the use of aqueous ammonia.

Table 7 presents the results of a cash flow analysis of the no-CO₂-capture, amine, and aqueous ammonia cases. Capturing only CO₂ using aqueous ammonia (Cases 3 and 5) has potential advantages over the amine case, but the multi-pollutant system with revenue from the sale of fertilizer is needed for aqueous ammonia to approach the NETL program goal of only a 20% increase in COE.

Table 7. Economic Results

Case		1	2	3	4	5	6
Sorbent		None	MEA	AA	AA	AA (USC) ¹	AA (USC) ¹
Component(s) Removed		None	CO ₂	CO ₂	CO ₂ , SO _x , NO _x , Hg	CO ₂	CO ₂ , SO _x , NO _x , Hg
CO ₂ Capture	Base Plant (\$/kWe)	1,072	1,460	1,218	1,225	1,157	1,164
	Gas Cleanup (\$/kWe)	197	239	288	215	277	215
	CO ₂ Capture (\$/kWe)	-	310	187	188	178	179
	Compression (\$/kWe)	-	122	108	108	103	103
	Total (\$/kWe)	1,270	2,132	1,801	1,736	1,715	1,661
	Capital COE (c/kWh)	2.68	4.50	3.80	3.66	3.62	3.51
	Variable COE (c/kWh)	1.90	2.91	2.36	1.67	2.24	1.73
	Total COE (c/kWh)	4.58	7.41	6.16	5.34	5.86	5.24
	\$/tonne CO₂ Avoided	-	43	23	11	20	10
Including CO₂ Transportation and Storage²							
Total	Total Capital (\$/kWe)	1,270	2,231	1,890	1,824	1,800	1,746
	Total \$/tonne CO₂ Avoided	-	47	27	14	23	13
	Total COE (c/kWh)	4.6	7.6	6.4	5.5	6.1	5.4
	Increase in COE	-	67%	39%	21%	32%¹	18%¹
Basis: 90% CO ₂ Capture, 80% Capacity Factor, 2003 Dollars, Coal \$28/ton							
¹ USC—Ultra-Supercritical Steam Cycle							
² CO ₂ Compression to 1,300 Psig, Transport 10 miles and Stored in Saline Formation 1,500 ft							
Sources: NETL Carbon Sequestration Economic Model; Evaluation of Innovative Fossil Fuel Power Plants with CO ₂ Removal, DOE/EPRI, 1000316							

The cost of the multi-pollutant gas cleanup system (NO_x and SO₂ to fertilizer) estimated for Cases 4 and 6 are lower than conventional NO_x and SO₂ controls (SCR and Wet Limestone FGD). However, to reach the DOE's program goal of 20% increase in COE, the operating revenue from the sale of the ammonium sulfate/nitrate fertilizer is necessary; decreasing the current CO₂ capture COE from 67% (amine scrubbing) to 21%. The cost associated with CO₂ transport and storage increases the CO₂ avoided cost by \$3/tonne and COE by 4-6 percent.

Figure 8 shows the breakdown of the parasitic load for each case. The results show that since CO₂ is produced from a low pressure system, the largest power requirement is for CO₂ compression. Therefore, any technology that has the potential to recover CO₂ at a higher pressure will have a large impact on the overall efficiency and cost of electricity.

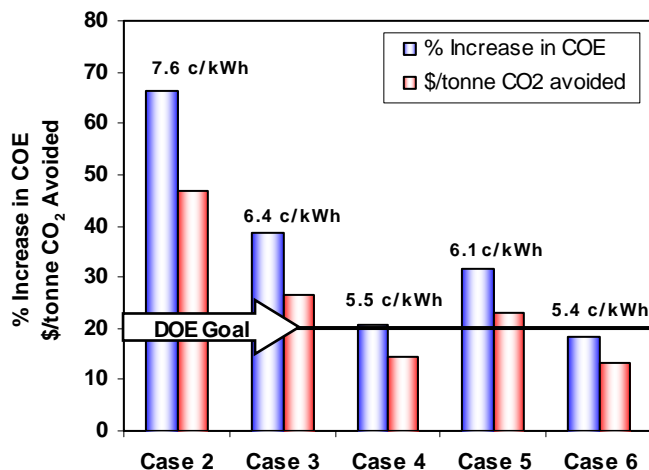


Figure 7. Economic Results

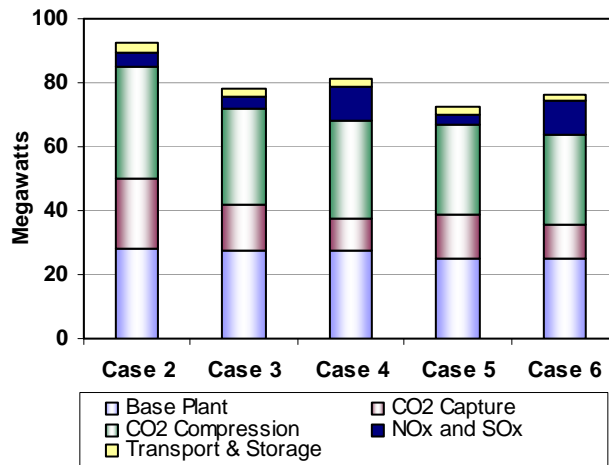


Figure 8. Auxiliary Power

Recommendations for Future Work

This initial analysis shows that aqueous ammonia technology has the potential to achieve the goals of NETL's Carbon Sequestration Program, but challenges remain. The temperature of the flue gas is hotter than is optimal for carbonate/bicarbonate absorption. Researchers are investigating options to accommodate this higher temperature. Also, ammonia may vaporize in the absorption tower, due both to high temperatures and operational transients. Ammonia loss would hurt the economics directly and may require costly tail gas control. Laboratory-scale testing and more rigorous process analyses and modeling to address these issues is recommended.

References

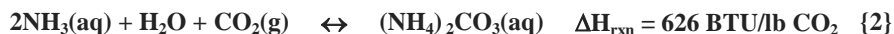
1. Carbon Sequestration Technology Roadmap and Program Plan, DOE/NETL, April, 2004
2. K.P. Resnik, J.T. Yeh, and H.W. Pennline, *Aqua Ammonia Process for Simultaneous Removal of CO₂, SO₂, and NO_x*, Int. J. Envr. Tech. Mgmt, 4(1/2), pp. 89-104, 2004.
3. *Evaluation of Innovative Fossil Fuel Power Plants with CO₂ Removal Report* U.S. Department of Energy – Office of Fossil Energy, Germantown, MD and U.S. Department of Energy/NETL, Pittsburgh, PA, EPRI, Palo Alto, CA,,: 2000. 1000316
4. “Gas Purification”, Arthur Kohl, Richard Nielsen, 5th Edition, Gulf Publishing Company, Houston, TX.
5. Cost algorithms developed by Howard McIlvried at SAIC
6. Max CO₂ loading taken from “Small Hydrogen Plant News” Rick Birnbaum of Dow Chemical sets 0.45 mole CO₂ / mole MEA as a maximum
7. *Recovery of CO₂ from flue gases: Commercial Trends*, G. Chapel, C. Mariz, J. Ernst, 1999. page 9 defines the delta as “approximately one quarter mole CO₂ per mole solvent”
8. Final Technical Report, “Engineering Development of FGD-Gypsum Conversion to Fertilizer and PCC,” M. Chou, Illinois State Geological Survey, ICCI Project Number 98-1/3.2A-2
9. International Fertilizer Association Webpage, IFA Databank, cell AP29, total N 2001/2002 <http://www.fertilizer.org/ifa/statistics/IFADATA/DATA/world.xls>
10. FGD Technologies Achieving SO₂ Compliance at the Lowest Lifecycle Cost, P Rader, J. Augeli, S. Aham of Alstom Power, presented in the CEPSI 2000, 23-27 October in Manila, Philippines.
11. Chemical Marketing Reporter “Ammonium Sulfate Market Relatively Stable” 7/21/2003 Ammonium Sulfate average of regional mid-ranges in the article
12. Chemical Marketing Reporter as of January 23, 2005
13. “Does AN have a future?” Nitrogen and Methanol 9/1/2003
14. DOE Fossil Energy web page updated August 2, 2004
http://www.fossil.energy.gov/programs/powersystems/pollutioncontrols/overview_mercurycontrols.html
15. http://www.boc.com/news/article_175_31oct01.asp
16. *Economic Evaluation of CO₂ Storage and Enhancement Options*, U.S. Department of Energy—National Energy Technology Laboratory, Pittsburgh, PA., Tennessee Valley Authority (TVA), Muscle Shoals, AL., EPRI, Palo Alto, CA., December 2002, 1005250
17. DiPriest, W., Pope, F., *Economic Evaluation of a Multi-Pollutant Control Approach for Ameren UE’s Sioux Plant*, Sargent & Lundy, 2004.

Appendix A.

I. Assumptions

Financial structure				
Capital Cost Year Dollars	2001		Federal Tax Rate	34.0 (%)
Project Book Life (n)	20	(years)	State Tax Rate	4.2 (%)
Projected Tax Life	20	(years)	Federal & State Tax Rate	38.2 (%)
Design/Construction	2.5	(years)	Investment Tax Credit	0 (%)
Inflation rate (e _i)	3.0	(%)	Property Tax Rate	1 (%)
Real Escalation Rate (e _r)	0.7	(%)	Insurance Tax Rate	1 (%)
Real Escalation Rate (O & M)	0.0	(%)	Initial Tax Depreciation Rate	0.075 (%)
Capital Structure				

II. Chemistry of CO₂ Capture with Aqueous Ammonia



III. Solvent Steam Load Requirements

$\text{Total}_{\text{regen energy}} = Q_{\text{sensible}} + Q_{\text{reaction}} + Q_{\text{strip}}$

Q sensible

MEA: 1,750 Btu/lb CO₂ vs. AA: 1,100 Btu/lb CO₂

Q reaction

MEA: 825 Btu/lb CO₂ captured vs. AA: 262 Btu/lb CO₂ (via Rxn #3)

Q stripping

MEA: 800 Btu/lb CO₂ (1 mole steam/mole CO₂) vs. AA: assume no stripping steam required

IV. Supplemental Economic Results

	Case 1 (SC)		Case 2 (SC)		Case 3 (SC)		Case 4 (SC)		Case 5 (USC)		Case 6 (USC)	
	No CO2 Capture		Amine Scrubbing		Ammonia CO2		Ammonia CO2+SO2+NO2+Hg		Ammonia CO2		Ammonia CO2+SO2+NO2+Hg	
Source	NETL		NETL		NETL		ECO: By-Product Credit		NETL		ECO: By-Product Credit	
Emission(s) Captured	0 % CO2		90 % CO2		90 % CO2		90 % CO2		90 % CO2		90 % CO2	
Capture Technology	No CO2 Capture		Amine Scrubbing		Ammonia CO2		Ammonia CO2+SO2+NO2+Hg		Ammonia CO2		Ammonia CO2+SO2+NO2+Hg	
Net Power (MW)	400		400		400		400		400		400	
Gross Power (MW)	425		492		478		482		473		476	
Power Plant CO ₂ Capture												
Base Plant (\$/kWe)	1,013	79.8 % of Tot.	1,380	64.8 % of Tot.	1,218	67.6 % of Tot.	1,225	70.6 % of Tot.	1,157	67.5 % of Tot.	1,164	70.1 % of Tot.
Gas Cleanup (\$/kWe)	257	20.2 % of Tot.	318	14.9 % of Tot.	288	16 % of Tot.	215	12.4 % of Tot.	277	16.2 % of Tot.	215	12.9 % of Tot.
CO ₂ Capture (\$/kWe)	0	0 % of Tot.	310	14.6 % of Tot.	187	10.4 % of Tot.	188	10.8 % of Tot.	178	10.4 % of Tot.	179	10.8 % of Tot.
Compression & Drying (\$/kWe)	0	0 % of Tot.	122	5.7 % of Tot.	108	6 % of Tot.	108	6.2 % of Tot.	103	6 % of Tot.	103	6.2 % of Tot.
Total Plant Capital Cost (\$/kWe)	1,271	N/A	2,130	68 % Increase	1,801	42 % Increase	1,736	37 % Increase	1,715	31 % Increase	1,661	27 % Increase
Capital COE (c/kWh)		2.68		4.50		3.80		3.66		3.62		3.51
Variable Cost (c/kWh)		1.90		2.91		2.36		1.67		2.24		1.73
Total Capture Busbar COE (c/kWh)	4.59	N/A	7.40	61 % Increase	6.16	34 % Increase	5.34	16 % Increase	5.86	27 % Increase	5.24	14 % Increase
\$/tonne CO ₂ Avoided	N/A	N/A	42.9 (157.6 /tonneC)	92 % of Tot.	23.4 (86 /tonneC)	88 % of Tot.	11.2 (41 /tonneC)	78 % of Tot.	19.8 (72.5 /tonneC)	86 % of Tot.	10 (36.8 /tonneC)	76 % of Tot.
CO ₂ Pipeline Transportation												
Equipment (\$/kWe)		0.0		15.1		13.3		13.3		13.2		13.2
Equipment COE (c/kWh)		N/A		0.03		0.03		0.03		0.03		0.03
Variable COE (c/kWh)		N/A		0.00		0.00		0.00		0.00		0.00
Total Transportation COE (c/kWh)		0.00		0.03		0.03		0.03		0.03		0.03
\$/tonne CO ₂ Avoided	N/A	N/A	0.5 (2 /tonne C)	1 % of Tot.	0.5 (1.7 /tonne C)	2 % of Tot.	0.5 (1.7 /tonne C)	3 % of Tot.	0.5 (1.7 /tonne C)	2 % of Tot.	0.5 (1.7 /tonne C)	4 % of Tot.
CO ₂ Underground Storage												
Storage Type		N/A		Saline Aquifer		Saline Aquifer		Saline Aquifer		Saline Aquifer		Saline Aquifer
Equipment Capital (\$/kWe)		0.0		83.8		73.9		74.2		71.8		72.0
Equipment Capital COE (c/kWh)		0.00		0.18		0.16		0.16		0.15		0.15
Variable COE (c/kWh)		0.00		0.02		0.02		0.02		0.02		0.02
Total Storage COE (c/kWh)		0.00		0.20		0.17		0.17		0.17		0.17
\$/tonne CO ₂ Avoided	N/A	N/A	3.2 (11.8 /tonne C)	7 % of Tot.	2.7 (10.1 /tonne C)	10 % of Tot.	2.8 (10.1 /tonne C)	19 % of Tot.	2.6 (9.7 /tonne C)	12 % of Tot.	2.7 (9.8 /tonne C)	20 % of Tot.
Carbon Sequestration Summary												
Total COE (Capture+Trans+Storage) (c/kWh)	4.59		7.63	67 % Increase	6.36	39 % Increase	5.54	21 % Increase	6.05	32 % Increase	5.43	18 % Increase
Total Capital Cost (\$/kWh)	1,271		2,229	75 % Increase	1,889	49 % Increase	1,824	44 % Increase	1,800	38 % Increase	1,746	34 % Increase
Total \$/tonne CO ₂ Avoided	0.00	N/A	46.70	171.4 /tonne C	26.66	97.8 /tonne C	14.40	52.8 /tonne C	22.87	83.9 /tonne C	13.16	48.3 /tonne C
CO ₂ Emissions (kg/kWh)	0.764	0.208 kg/kWh C	0.108	0.029 kg/kWh C	0.092	0.025 kg/kWh C	0.092	0.025 kg/kWh C	0.086	0.023 kg/kWh C	0.086	0.024 kg/kWh C
Efficiency (% HHV)		40%		29%		34%		33%		36%		36%
Heat Rate (Btu/kWh)		8,453		11,896		10,139		10,211		9,489		9,565
Energy Penalty (%)				28.9%		16.6%		17.2%		15.9%		16.5%